



**Director's Report**  
**For Indiana Municipal Power Agency's 2020**  
**Integrated Resource Plan**

**December 21, 2021**

**Dr. Bradley Borum**  
Director of Research, Policy and Planning  
on behalf of the Indiana Utility Regulatory Commission

## TABLE OF CONTENTS

I. PURPOSE OF IRPS.....	3
II. INTRODUCTION AND BACKGROUND .....	4
III. FOUR PRIMARY AREAS OF FOCUS.....	4
A. Load Forecast .....	5
Director’s Comments – Load Forecasting .....	8
B. Energy Efficiency .....	12
Director’s Comments – Energy Efficiency .....	13
C. Resource Optimization and Risk Analysis .....	14
Director’s Comments – Resource Optimization and Risk Analysis .....	15
D. Future Enhancements to IMPA’s IRP Processes .....	19
Director’s Comments - Future Enhancements to IMPA’s IRP Processes .....	19
IV. SUMMARY.....	20
V. STAKEHOLDER COMMENTS .....	21

# Director's Report Applicable to Indiana Municipal Power Agency's 2020 Integrated Resource Plan and Planning Process

## I. PURPOSE OF IRPS

Indiana Municipal Power Agency's (IMPA's) 2020 Integrated Resource Plan (IRP) was submitted on Nov. 2, 2020. By statute<sup>1</sup> and rule, integrated resource planning requires each utility that owns generating facilities to prepare an IRP and make continuing improvements to its planning as part of its obligation to ensure reliable and economical power supply to the citizens of Indiana. A primary goal is a well-reasoned, transparent, and comprehensive IRP that will ultimately benefit customers, the utility, and the utility's investors. At the outset, it is important to emphasize that these are the utilities' plans. The Director's report does not endorse the IRP nor comment on the desirability of the utility's "preferred resource portfolio" or any proposed resource action.<sup>2</sup>

The essential overarching purpose of the IRP is to develop a long-term power system resource plan that will guide investments to provide safe and reliable electric power at the lowest delivered cost reasonably possible. Because of uncertainties and accompanying risks, these plans need to be flexible as well as support the unprecedented pace of change currently occurring in the production, delivery, and use of electricity. IRPs may also be used to inform public policies and are updated regularly.

IRPs are intended to be a systematic approach to better understand the complexities of an uncertain future, so utilities can maintain maximum flexibility to address resource requirements. Inherently, IRPs are technical and complex in their use of mathematical modeling that integrates statistics, engineering, and economics to formulate a wide range of possible narratives about plausible futures. The utilities should utilize IRPs to explore the possible implications of a variety of alternative resource decisions. Because of the complexities of IRP, it is unreasonable to expect absolutely accurate resource planning 20 or more years into the future. Rather, the objective of an IRP is to bolster credibility in a utility's efforts to understand the broad range of possible risks that utilities are confronting.<sup>3</sup> By identifying uncertainties and their associated risks, utilities will be better able to make timely adjustments to their long-term resource portfolio to maintain reliable service at the lowest reasonable cost to customers.

IMPA, like every Indiana utility and stakeholder, anticipates substantial changes in the state's resource mix due to several factors<sup>4</sup> and, increasingly, Indiana's electric utilities are using IRPs as a

---

<sup>1</sup> Indiana Code § 8-1-8.5-3.

<sup>2</sup> 170 IAC 4-7-2.2(g)(3).

<sup>3</sup> In addition to forecasting changes in customer use of electricity (load forecasting), IRPs must address uncertainties pertaining to the fuel markets, the future cost of resources and technological improvements in resources, changes in public policy, and the increasing ability to transmit energy over vast distances to access economical and reliable resources due to the operations of the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM).

<sup>4</sup> A primary driver of the change in resource mix is due to relatively low cost natural gas and long-term projections for the cost of natural gas to be lower than coal due to fracking and improved technologies. As a

foundation for their business plans. Since Indiana is part of a vast interconnected power system, Indiana is affected by the enormity of changes throughout the region and nation.

The resource portfolios emanating from the IRPs should not be regarded as being the definitive long-term plan that a utility commits to undertake. Rather, IRPs should be regarded as illustrative or an ongoing effort that is based on the best information and judgment at the time the analysis is undertaken. The illustrative plan should provide off-ramps to give utilities maximum optionality to adjust to inevitable changing conditions (e.g., fuel prices, environmental regulations, public policy, technological changes that change the cost effectiveness of various resources, customer needs, etc.) and make appropriate and timely course corrections to alter their resource portfolios.

## II. INTRODUCTION AND BACKGROUND

IMPA is a wholesale electric utility providing long-term electricity requirements<sup>5</sup> for its 61 member communities under long-term power sales contracts. IMPA's member cities and towns own and operate an electric distribution utility. In 2019, IMPA's coincident peak demand for its communities was 1,198 MW and the annual member energy requirements during 2019 were 6,244,150 MWh. IMPA projects that its peak and energy will grow at approximately 0.5% per year. These projections do not include the addition of any new members or customers beyond those currently under contract. (*IMPA IRP – page 2-13*)

IMPA operates in both the Midcontinent Independent System Operator (MISO) and PJM Interconnection, LLC (PJM) regional transmission organizations (RTOs). IMPA has member load in five load zones and generation resources connected to six zones within the RTOs, plus two resources outside of the RTOs. IMPA's load is approximately two-thirds within MISO and one-third in PJM. Given that IMPA serves wholesale load in both the MISO and PJM, (*IMPA IRP page 5-23*) IMPA must comply with the resource adequacy requirements of each RTO for its load in that RTO. (*IMPA IRP page 4-19*)

## III. FOUR PRIMARY AREAS OF FOCUS

Consistent with IMPA's comment about significant challenges, the primary areas of focus of the Director's comments include the interrelated topics of: load forecasting; demand side management (DSM), which includes energy efficiency (EE) and demand response (DR); and risk scenario analysis. Throughout, there will be a discussion of continual improvements to all aspects of IRP.

---

result, coal-fired generating units are not as fully dispatched (or run as often) by MISO or PJM. The aging of Indiana's coal fleet, the dramatic decline in the cost of renewable resources, the increasing cost-effectiveness of energy efficiency as a resource, and environmental policies over the last several decades that reduced emissions from coal-fired plants are also drivers of change.

<sup>5</sup> IMPA's resources include: Joint ownership interests in Gibson Station #5, Trimble County Station #1 & #2 and Prairie State Energy Campus #1 and #2• Operation and maintenance responsibility of Whitewater Valley Station #1 & #2; Five dual fuel, natural gas or No.2 fuel oil, fired combustion turbines owned and operated by IMPA; Two natural gas fired combustion turbines owned by IMPA and operated by Indianapolis Power and Light ; 32 Solar Parks located in member communities; Long term power purchases from: Indiana Michigan Power Company, Duke Energy Indiana , Alta Farms II, Wind Farm LLC, Ratts Solar Park LLC; Short term contracts with market participants in MISO and/or PJM, and the IMPA Energy Efficiency Programs. (*IMP IRP page 5-24*)

The continual improvements include enhancements to load forecasting and risk analysis. IRP improvements should include an expansive definition of distributed energy resources (DERs) that subsume DSM as well as other resources such as rooftop solar, combined heat and power, microgrids, and storage which might be part of hybrid energy systems (HES). Because electric vehicles (EVs) have the potential for affecting resource requirements, it is imperative that IMPA understand the ramifications for IMPA and its 61 members. For both DERs and EVs it is also necessary for IMPA to develop full avoided costs to determine the benefits and costs of DERs and EVs and to integrate DERs and EVs.

## **A. Load Forecast**

IMPA conducted a “back-cast” to try to understand the effect of the COVID-19 pandemic on IMPA’s long-term load forecast. IMPA noted MISO and PJM conducted similar analyses comparing modeled load to actual load. While the emphasis of the IRP rule is on the long-term load forecast, a back cast may provide potential information on the impact of relatively short-term situations such as a recession, a polar vortex, or a pandemic to better assess risks. To improve the forecast in the face of COVID-19, IMPA staff attempted to incorporate macroeconomic variables in the forecast model that would be sensitive to COVID-19. This included but were not limited to Producer Price Index (PPI), Indiana ongoing jobless claims, ADP Construction Payrolls, ADP Manufacturing Payrolls, and average weekly jobless claims. It became rapidly apparent that regression models would not be able to sufficiently explain or capture movements seen in those variables as they became impacted by COVID-19. For example, initial jobless claims in the first weeks of the COVID-19 outbreak were unfathomable and were such an outlier that they caused the regression model to fail. (*IMPA IRP page 1-9 through 1-10*) IMPA engaged in an assessment of the load forecast process and concluded it was appropriate to maintain its model for load forecasting for this IRP, at least until more COVID-19 data is captured. (*IMPA IRP page 6-38*)

IMPA’s longer-term forecast notes:

IMPA transitioned to a unifying model for 4 of its 5 load zones after its last IRP was filed. This involved finding regression variables that satisfactorily explained movements in all of IMPA’s major load zones (Duke-IN, NIPSCO, Vectren, AEP). With prior efforts laying the groundwork for a unifying regression, the variables chosen were: On and Off-Peak Days (as defined by NERC), Heating Degree and Cooling Degree Days for the respective area weather station, a dummy variable for winter/summer peak, energy intensity (btu per dollar of real GDP), and finally real U.S. GDP in average annual dollars. (*IMPA IRP page 6-38*)

The tables below illustrate the regression statistics for each of IMPA’s largest load zones.

**Table 5 Energy Forecast Variables & Regression Statistics**

<i>T-Stats &amp; Selected Regression Statistics by Zone</i>									
Area	Peak Days	Off-Peak Days	Relevant Weather Station HDD	Relevant Weather Station CDD	Peak Season Dummy	Energy Intensity (btu/\$ of GDP)	Annual Real GDP (average annual \$)	Model R^2	Observations
DUK-IN	10.5	9.7	14.6	20.9	5.8	8.1	7.4	0.94	168
NIPSCO	7.3	4.4	3.7	9.9	2.3	4.0	8.3	0.83	168
Vectren	9.0	6.6	4.7	17.1	4.2	9.6	4.4	0.94	168
AEP	8.1	7.1	13.7	13.4	5.7	2.9	3.8	0.87	168
DUK-OH	3.7	3.5	8.0	7.8	4.1	16.5	N/A	0.90	132

IMPA’s smallest load zone in DUK-OH, is one zone where the data do not fit as well and so that load gets a similar model but excludes real GDP. Peak load forecasts are driven by hourly variables and are dependent on daily weather (i.e., wind speeds, temps), but are largely driven by the monthly energy forecast broken into a peak day shape for given peak day weather variables. (IMPA IRP page 6-39 includes the table on the previous page)

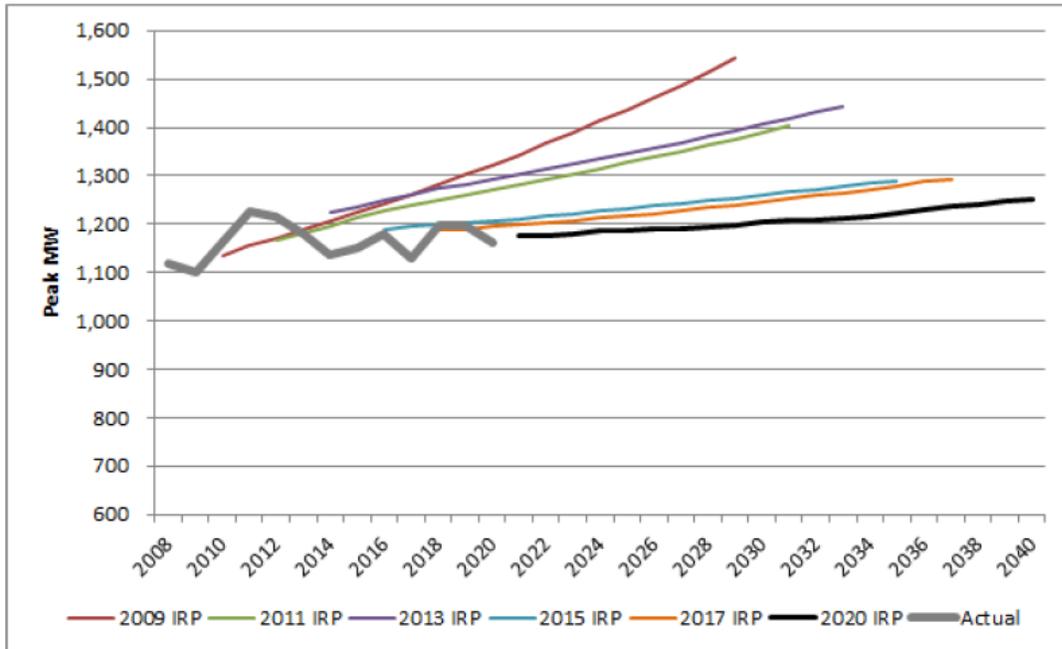
IMPA is predicting low load growth over the forecast period. Electric vehicle penetration is a potential future source of load growth but IMPA does not anticipate this as a significant factor. Risks to the load forecast are skewed to the downside given the increased penetration of behind the meter generation, increased efficiency, and specific to IMPA, constrained service territory due to changes in state law. The following table illustrates the annual energy and peak demand requirements of IMPA over the next 20 years. (IMPA IRP page 6-41)

**Table 6 IMPA Total Energy and Peak Demand Forecast**

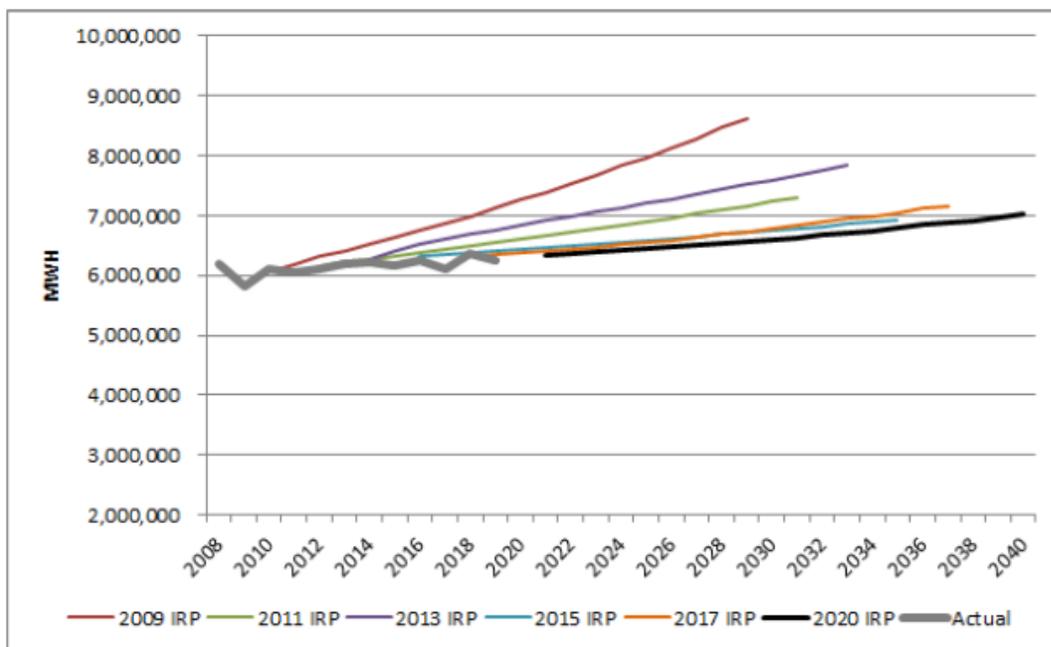
Year	IMPA Total Energy (GWh)	IMPA Peak
2021	6,338	1,178
2022	6,349	1,179
2023	6,370	1,180
2024	6,394	1,183
2025	6,436	1,189
2026	6,450	1,192
2027	6,474	1,194
2028	6,503	1,196
2029	6,543	1,197
2030	6,561	1,202
2031	6,594	1,207
2032	6,628	1,211
2033	6,680	1,213
2034	6,703	1,216
2035	6,742	1,220
2036	6,785	1,226
2037	6,843	1,232
2038	6,876	1,239
2039	6,923	1,244
2040	6,973	1,250

The following figures compare the IMPA peak demand and energy forecast used in the last five IRPs with actual results. As the below graphics demonstrate, IMPA's historic projected peak demand and energy shows very little load growth, which is similar to the types of trajectories that other Indiana utilities are projecting to experience over the next 20 years. (IMPA IRP page 6-42)

**Figure 14 Load Forecast Performance – Peak Demand**



**Figure 15 Load Forecast Performance – Energy Requirements**



IMPA's load forecasting is characterized as a top/down approach. Since IMPA does not sell directly to retail customers, it does not have direct access to retail customer billing information. IMPA noted the criteria determining member rate classes can change and it would be nearly impossible to ensure consistent sector data back through the historical period. Finally, different members identify sectors (or classes) of customers differently which makes comparisons difficult, especially over time. *(IMPA IRP page 6-43)*

IMPA discussed an end-use (a bottom-up) forecast method, which would require detailed information on appliance saturations and usage patterns in the residential sector, data on building and business types in the commercial sector and detailed equipment inventories, lighting types, and square footage area in the industrial sector. However, IMPA contends the data requirements for an end-use model are too extensive given that IMPA's member communities are not uniform and would necessitate large sample sizes for surveys to develop the necessary information. All of which would be quite expensive. *(IMPA IRP page 6-43)*

The current status of customer-owned resources and the potential benefits are articulated in IMPA's IRP.

As of the date of this report, IMPA has contracted with 28 customers, totaling 2.4 MW of installed renewable energy systems. IMPA has a contract with one commercial/industrial customer of an IMPA member to purchase excess generation from its onsite generation facilities. Under the current contract, the customer has been selling small amounts of energy to IMPA under a negotiated rate. IMPA does not currently have any customers on the system that operate a combined heat and power (CHP) system. While under the right circumstances CHP systems could be beneficial to both the customer and IMPA, the right mix of site-specific operating conditions and economics must be in place for both parties for a CHP project to go forward. Except for emergency back-up generators at some hospitals, factories and water treatment plants, IMPA knows of no other non-renewable retail customer generation in its members' service territories. *(IMPA IRP page 5-29)*

### **Director's Comments – Load Forecasting**

IMPA's commentary on short-term, low probability, but highly consequential events is well-taken because projecting load over many years is fraught with uncertainty even without the existence of a pandemic. As IMPA notes, some events are very short in duration (e.g., the Polar Vortex) but the long-term effects of the COVID-19 pandemic may have significant ramifications for long term load, though it is too soon to know. IMPA's use of the Producer Price Index (PPI), Indiana ongoing jobless claims, ADP Construction Payrolls, ADP Manufacturing Payrolls, and average weekly jobless claims as explanatory variables to help identify the potential impact of the pandemic on long-term load is appreciated. However, IMPA is correct that regression models would not be able to sufficiently explain or capture the effects of such a significant event, especially something so recent that is continuing to develop. Kudos for IMPA raising this important forecasting issue and for highlighting short-term but significant risks.

The load forecast section of IMPA's 2020 IRP is somewhat confusing. The forecast starts out the same as its 2017 IRP but includes far fewer details than in 2017. "IMPA decided to maintain its model for load forecasting for this IRP." However, the very next sentence states: "IMPA transitioned to a unifying model for 4 of its 5 load zones after its last IRP was filed." This is confusing. If IMPA is maintaining the model, that would seem to imply not changing the model. A unifying model suggests IMPA combined four of its five load zones into one model. Inexplicably, Table 5 presents

the T-stats and R-squared results for five separate models suggesting IMPA did not combine zones. This adds to the confusion. The description of the chosen variables and revisiting IMPA's 2017 IRP seems to clarify "unifying" as using the same set of explanatory variables in four of the five load zones whereas, in prior IRPs, the four models had varying sets of drivers. The reader should not have to re-read a previous IRP to understand what was done. (*IMPA IRP page 6-38*)

#### IMPA's Response to Director's Comments

"With respect to the Director's comments regarding confusion in the load forecast write-up (page 8), IMPA apologizes for the lack of clarity. Ultimately, IMPA was attempting to convey that its priority was to quantify any permanent loss of load from the COVID-19 pandemic. Once that proved to be difficult, IMPA then audited the old forecast for performance and decided to maintain the basic load forecast methodology (i.e., top down), tweaking the approach to try to find variables that work for each of the five load zones. In essence, IMPA was trying to retain the independent forecasts for each of the five load zones but with as many common variables as statistically possible. Ultimately, this is what IMPA tried to convey in Table 5 of the IRP; five load zones using the same variables but each with their own regression statistics. Annual real GDP was excluded from the DUK-OH zone due to poor regression statistics, as the Director surmises." (*IMPA's Response to Director's Draft Report, page 1*)

#### Director's Reply

*The Director appreciates the clarification provided by IMPA.*

Overestimation was noted for the NIPSCO zone and was thought due, in part, to the winding down of operation at St. Joseph's College in Rensselaer. IMPA said removing that load from the historical database or using a simple dummy variable should correct the forecast models. However, IMPA never states whether they actually used a dummy variable or adjusted the historical data. (*IMPA IRP page 6-38*)

#### IMPA's Response to Director's Comments

"Regarding the NIPSCO load zone forecast (page 9), IMPA noted that on a going forward basis, either stripping the load out or utilizing a dummy should correct the overestimation. At the time of writing, IMPA was also seeing some declines in specific wholesale meters but had not tracked down root causes for the declines. Since filing, IMPA has revised the NIPSCO load forecast utilizing a dummy variable, to account for both the closure of St. Joseph's College and the additional, potentially COVID-related declines seen in some locations." (*IMPA's Response to Director's Draft Report, pages 1 - 2*)

#### Director's Reply

*The Director appreciates the analytical effort to capture the over-estimation. Historically, the Director has urged utilities to avoid using dummy variables. While dummy variables are often useful, they may not have long-term explanatory value. For this reason, we urge IMPA to undertake a closer examination of drivers that could be more insightful. In future IRPs, a discussion of the use of dummy variables would be helpful.*

IMPA states its smallest load zone DUK-OH [Duke -Ohio] data does not fit well so real GDP is excluded from the model. But the DUK-OH R-squared is actually higher than two of the other load zones and the T-stats are not lower across the board either. Perhaps IMPA meant the DUK-OH model, with GDP included, was universally worse. Detailing the results would be useful. *(IMPA IRP page 6-39)*

The model variables are on- and off-peak days as defined by the North American Electric Reliability Corporation (NERC), heating degree days, cooling degree days, dummy variable for winter/summer peak, energy intensity (Btu per dollar of real GDP), and annual real GDP (except, again, for DUK-OH model). There is no mention of the source for any of the driver data. IMPA did not clarify what was meant by “On/Off Peak Days” as a variable. IMPA did not articulate what temperature base was used for the heating and cooling degree days. The text says, “dummy variable for winter/summer peak” were used but Table 5 says “Peak Season Dummy.” These do not sound like the same descriptor. What geographic region (state/census region/national) is used for the economic variables? *(IMPA IRP page 6-39)*

#### IMPA’s Response to Director’s Comments

IMPA provided source data and summary descriptions for each explanatory variable used. *(IMPA’s Response to Director’s Draft Report, page 2)*

#### Director’s Reply

*The Director appreciates the additional information and encourages IMPA to provide similar documentation in future IRPs. The data sources are appropriate. However, the Director continues to urge IMPA to develop more IMPA specific data to enable IMPA to gain valuable insights into their member systems’ needs. It bears reporting that developing and utilizing databases is a difficult undertaking, but it is essential for a credible planning regime.*

The following statement is the extent of the discussion of IMPA’s peak forecasting and is far from clear or sufficient: “peak load forecast are driven by hourly variables and are dependent on daily weather (i.e. wind speeds, temps), but are largely driven by the monthly energy forecast broken into a peak day shape for given peak day weather variables.” *(IMPA IRP page 6-39)*

#### IMPA’s Response to Director’s Comments

IMPA clarified that it used a seasonal peak forecast model for each of the five load zones and provided a table showing the explanatory variables used by zone and by season. IMPA stated that the peak load methodology was unchanged from the previous IRP. Tables for each load zone provided the regression statistics by season. *(IMPA’s Response to Director’s Draft Report, pages 2 - 7)*

#### Director’s Reply

*The Director appreciates the additional information and encourages comparable documentation be provided in future IRPs either in the body of the IRP report or in an appendix.*

While IMPA recognized the potential for DERs and EVs to have a significant effect on the load forecast, especially in the long run, there was discussion on the implications for DERs and EVs. It is not clear, however, that IMPA constructed any risk bands around its load forecasts. There was no

discussion of explicit risk bands or development of alternative scenarios to test even modest changes and certainly nothing that would constitute a stress test.

#### IMPA's Response to Director's Comments

"With respect to risk banding the load forecasts (page 9), IMPA believes the most appropriate method of doing this is through the extensive Monte Carlo work it does on each of the candidate portfolios. These Monte Carlo simulations account not only for risks in commodity prices, but also loads while capturing the correlation between all interrelated variables. IMPA believes constructing risk bands around load forecasts, while instructive, does not fully capture the portfolio risk associated with the uncertainty around the load." (*IMPA's Response to Director's Draft Report, page 7*)

#### Director's Reply

*This seems to be a question of stochastic analysis vs. deterministic. The Director has tried to emphasize that a stochastic approach is not a substitute for deterministic scenario analysis. Rather, these two approaches should be regarded as complimentary perspectives. It is accurate to say that both have benefits and limitations. IMPA seems to understand this as an either / or question. In many cases, it would be helpful to do both, not just one or the other to realize the benefits of different perspectives.*

IMPA states that one of the risks to the forecast is "constrained service territory due changes in state law". What change to state law does this refer to? (*IMPA IRP page 6-40*). It would be helpful if more detail was provided to better understand the implications.

#### IMPA's Response to Director's Comments

The state law to which IMPA referred to is Indiana Code 8-1-2.3-6 which was changed in 2015 to disallow municipal electric utilities from expanding their assigned service territory when the city or town annexes new land into the city/town boundaries. (*IMPA's Response to Director's Draft Report, pages 7*)

#### Director's Reply

*The Director thinks it is good practice to explicitly cite any law or regulation referred to in an IRP.*

IMPA faces a longer-term dilemma should EVs and DERs increase in importance more quickly than it thinks likely. IMPA recognizes that it does not have the detailed information necessary to project the ramifications of DERs, EVs, and other infrastructure enhancements that may eventually result in dramatic changes for the operations and planning of IMPA and the distribution systems operated by member communities.

Even without developing a bottom-up forecast, it may be possible to develop detailed load research information from other Indiana utilities that would provide the detailed granularity that is essential to forecast the penetration and implications of DERs and EVs. IMPA could consider data from other Indiana utilities that is more specific to the five zones detailed by IMPA.

## IMPA'S Response to Director's Comments

"IMPA agrees with the director that, long term, electric vehicle (EV) penetration could become a factor driving load growth (page 9). IMPA communities have demographic and economic trends that may not support as rapid of near-term EV penetration as other areas of the state....

IMPA did not explicitly model increased EV load not because it does not believe EV will influence future loads, but due to a lack of information on how large or how fast expansion of EV use will occur in the member communities. Before planning for EV load, IMPA thought it better to understand the potential growth from a time and volume perspective. IMPA will continue to analyze EV impacts in member communities and its effect on IMPA's load and load shapes." (*IMPA's Response to Director's Draft Report, page 8*)

### Director's Reply

*The Director agrees with IMPA that EVs and EV infrastructure will not experience the higher penetration rates that large cities will experience. More importantly, EVs and integration of DERs require similar analysis (including granular usage data) to better predict the development of EVs and DERs. So, IMPA should think more expansively and holistically. IMPA's circumstances provide an excellent opportunity for it to learn from the experience of other utilities, especially on the methods and data most helpful to understanding the basis for customer choices. IMPA has the challenge of how best to adapt and learn from others to fit what works best for IMPA and its members.*

## **B. Energy Efficiency**

IMPA's energy efficiency program offers incentives in the form of rebates for residential, Commercial, and industrial (C&I) customers. Since 2012, IMPA's energy efficiency programs<sup>6</sup> generated a cumulative savings of 120,214 MWh at the end of 2019 and a coincident peak reduction of 13.5 MW. In addition to energy efficiency programs, IMPA offers a demand response tariff, an excess renewable generation program, and education. Furthermore, many IMPA members utilize various rate structures aimed at assisting customers in lowering or controlling their energy consumption or bills. (*IMPA IRP page 2-14*)

IMPA's members have implemented programs and projects to reduce peak demand and encourage efficient energy use. Most of these programs are rate and customer service related (e.g., coincident peak rates, off-peak rates, power factor improvement assistance, etc.). As in the 2017 IRP and in

---

<sup>6</sup> Existing demand-side resources consist of programs coordinated by IMPA as well as those implemented by its members include: "In early 2011, IMPA launched the IMPA Energy Efficiency Program, designed to help retail customers in the Agency's member communities save money through incentives for implementing energy-saving measures in four different categories: energy efficient lighting; heating, ventilation and air conditioning (HVAC); motors, fans & drives; and refrigeration, food service and controls. IMPA worked with member utilities to market the program, educate customers and build relationships with local vendors to implement the energy saving measures. During 2011, the Agency as a whole saw approximately 90 companies participate in the program, representing 25 member communities throughout the state of Indiana. In 2012 and 2013, IMPA voluntarily participated in Energizing Indiana, a state-wide energy efficiency program in order to gain experience and evaluate the cost-effectiveness of a variety of residential, commercial, and industrial programs. The savings from these efficiency efforts was 32 million kWh (2012) and 52.7 million kWh (2013), annually." (*IMPA IRP 5-30 through 5-31*)

this new IRP, no customers are reported to participate in the DR programs offered under the MISO and PJM tariffs. (*IMPA IRP page 5-32*)

### **Director's Comments – Energy Efficiency**

The 2020 IRP has a better explanation of EE modeling in Aurora<sup>XMP</sup> (Aurora is an electric utility modeling and forecasting software). As before, IMPA continues to use Aurora to determine the lowest cost resource mix for the various market areas modeled. The model develops various tranches of EE which are included as part of the resource options permitted to be selected by the portfolio optimizer. These tranches effectively act as decrements to IMPA load. That is, IMPA stated that the EE and DR programs were modeled as selectable resources. IMPA also said that EE and DR were treated as load decrements at incrementally higher costs. The initial block of EE was modeled in quarter MW increments, with the initial one-quarter being modeled at IMPA's current implementation cost. According to IMPA, this approximated the forward wholesale power price. Additional increments were priced on an increasing basis reflecting the "low hanging fruit" and it being increasingly difficult to find efficiencies as more end-users adopt energy efficiency measures (e.g., replace lighting and appliances).

The Director understands that IMPA's structure and relationship with its members imposes several complications, but IMPA's IRP discussion of the analysis of DSM suffers from an almost complete lack of information on the methodology and data used by IMPA. The failure in communication is such that IMPA does not even say if DSM was selected in the optimization.

It is not clear what load research data was used by IMPA to construct the "blocks." Without information on how the blocks were constructed, it is difficult to assess how the blocks were optimized on a reasonably comparable basis to other resources, especially since the analysis and results did not explicitly appear in expansion plans.

IMPA's explanation of how it decremented existing and future DSM from the load forecast was unclear. There was no detail on how the current and projected cost of DSM implementation are determined. What is the "approximated to forward price of wholesale power"? How were the additional MW increments priced? (*IMPA's IRP pages 11-68*). A more in-depth explanation about the EE modeling methodology used in this IRP and future IRPs will help the readers to have a better understanding of the integration of DSM into the modeling process.

### **IMPA's Response to Director's Comments**

"From a planning perspective, IMPA's solution to this was to create, as mentioned, EE load decrements in tranches. The first tranche was intended to represent IMPA's existing program based on IMPA's historical annual cost of implementation per MWh saved per year. IMPA's initial EE load decrement tranche was priced accordingly, while the next tranches were priced at increasingly higher costs. The goal of having increasing costs for the subsequent tranches was to reflect the increasing cost, difficulty and diminishing returns of more complex solutions. IMPA acknowledges that these later tranches were not well defined in the IRP text and did not represent any specific EE programs. IMPA will attempt to improve the data flow between member utilities in an effort to expand the EE modeling and future program delivery.

Regarding the director's comments about borrowing AMI and load research data (page 9-10), IMPA's engineering subsidiary, IMPA Service Corporation, is currently assisting some

members with the installation of AMI systems. At this time, the program is in its early stage with only a few thousand meters installed. IMPA's planning staff hopes to be able to work with some of the members to utilize some of the AMI data to assist in load forecasting and EE. IMPA will endeavor to more thoroughly review EE and demand side programs over the coming years." (*IMPA's Response to Director's Draft Report, page 9*)

### Director's Reply

*The Director appreciates the difficulty of modeling energy efficiency in long-term resource optimization models. Numerous characteristics of EE measures need to be appropriately evaluated if the inclusion of EE as a resource option in the optimization model is to be useful and informative. The difficulty of this exercise was recently highlighted in the three Contemporary Issues Workshops conducted this past summer. The exercise of considerable judgement is unavoidable so the discussion of how EE was evaluated in the IRP needs to be fairly detailed so that readers can better understand what was done, how, and why.*

*The Director is gratified that IMPA is making a concerted effort regarding AMI. The suggestion of supplementing IMPA's data with data from other utilities is intended to be a stopgap measure until IMPA has statistical confidence in its IMPA specific data. As demonstrated by the Summer 2021 Contemporary Issues Workshops, the use of load shape information will be increasingly important to evaluate the cost-effectiveness of EE measures relative to each other and other resource options. More importantly, AMI may be helpful for improvements in load forecasting and to better understand customer choices involving EVs and DERs.*

Accurate assessment of relevant costs to establish the dynamic values of EE and DR by time and location is necessary for IMPA and its member communities to calculate the value of DSM. That is, IMPA needs to consider all avoided costs which include generation, transmission, and distribution systems. It is not apparent that IMPA and its members have attempted to calculate full avoided costs which is likely to understate the value of EE (and other DERs).

### **C. Resource Optimization and Risk Analysis**

IMPA articulated its approach to risk analysis in developing its long-term resource plans as to "plan for the best expectation of future events based on information that is currently known..."

The plan outlined in the following report may very well change depending on the outcomes of the pandemic and elections. IMPA believes the best way to combat this uncertainty is to rigorously plan for the best expectation of future events based on information that is currently known. More importantly, IMPA believes in the power of being adaptable and nimble as market conditions dictate. By doing this, IMPA can continue to supply wholesale power to our 61 communities. Power that is low cost, reliable and environmentally responsible. (*IMPA's IRP page 1-11*)

IMPA used Aurora for resource expansion modeling, market price studies and portfolio optimization. IMPA, then, utilized MCR-FRST by MCR Performance Solutions, LLC to develop the final revenue requirements for each portfolio.

IMPA modeled the entire PJM and MISO in its expansion planning. A complete regional capacity expansion plan and the corresponding wholesale price for energy and capacity were determined for each scenario. The regional capacity expansion plan generated a list of eligible assets for selection

for IMPA to create the optimized portfolio under each scenario. The market prices for capacity and energy from the regional capacity expansion plan were used as inputs in the IMPA's portfolio optimization as well.

IMPA modeled three different future paths and created an optimized portfolio for each path. The three future cases are the Base Case, Green Case and High Growth Case. The Base case optimal portfolio picked a combustion turbine (CT) and solar to replace Gibson 5 a coal-fired unit, while the optimal portfolios for the Green Case and High Growth Case included new combined cycle (CC and some renewables following the retirement of Gibson 5.

After the candidate portfolio being identified by the Aurora optimization, the risk of each portfolio was evaluated. Risk drivers including NG price, coal price, MISO system load, PJM system load, emission costs and IMPA load were included as stochastic parameters. The volatility and correlations of the risk drivers were first established based on historical data. These risks drivers were then modeled stochastically through simulation and were used to test the candidate portfolio for risk exposures and robustness to those exposures.

### **Director's Comments – Resource Optimization and Risk Analysis**

Risk analysis was conducted with a variety of appropriate analytical tools including Aurora. IMPA developed risk profiles and tornado charts (*IMPA IRP page 11-97*) to good effect in this IRP and in prior IRPs. As a measure of robustness, IMPA opted to perform stochastic runs where the Green Case and High Growth Case portfolios were implemented in the Base Case scenario to make the performance of the three candidate portfolios more comparable. IMPA believes that installation of a CT covers IMPA's capacity position while still giving IMPA sufficient flexibility to meet changing load, regulatory and environmental conditions. Based on its analysis, IMPA recommended the Base Case portfolio to cover IMPA's capacity and energy needs when Gibson 5 is retired. It is not clear if IMPA performed an analysis of how the Base Case Portfolio performed under the two other scenarios. The short-term action plan is consistent with the preferred plan selected.

#### IMPA's Response to Director's Comments

“To clarify the Director's comment regarding whether IMPA studied the Base Case Portfolio in the other two cases (page 10), IMPA did not. The reason for this is because within Aurora you first must begin with a given set of deterministic assumptions that results in a market build plan that is optimized for that deterministic world view. Challenges arise when build plans vary greatly between cases. In this year's IRP, there were no CTs built in the Green Case, which would have ruled out their selection for a “base case” plan in the Green Case market expansion. In other words, if the base plan built a CT and the optimization selected the CT for the portfolio, that same portfolio could not be replicated in the Green Case as the CT needed was never constructed. In summary, the ability to run scenario-specific portfolios across different world views in Aurora is not always forward and backward compatible due to limitations of optimized market expansion in each world view. In theory, IMPA could have introduced the needed supply to the Aurora optimized footprint, but this would potentially yield disconnects between market prices for energy and capacity. In future IRPs, IMPA will enhance and improve this aspect of its modeling portfolios across different world views.” (*IMPA's Response to Director's Draft Report, page 10*)

## Director's Reply

*The Director is confused by IMPA's second point. The idea behind running the base scenario's portfolio through the other scenarios is to see how well (or poorly) that portfolio works if the world turns out differently. To do this, you would not try to replicate the lack of Combustion Turbine (CT) in the Green Case. You would try to identify the extra costs associated with building the CT when it turns out we are living in a Green Case world. You would, then, fix the Base Case portfolio in Aurora and run the production costing part of the model. As a side note, it should be noted that there are limitations to this. For instance, it inherently assumes a stubbornness that once you start down the Base Case path, you will stay on it throughout the planning horizon, even in the face of mounting evidence that you are living in a Green Case world. This is particularly true for resources that are added later in the analysis period. Using IMPA's example, if the CT was being constructed 15 years down the road, they should realize before they build it that it wouldn't be the best choice and change paths. That's one reason why the focus on the decisions that have to be made in the first 5 years are so important. That is the evaluation of an IRP would show those resources that could truly be at risk of being wrong resource selections to the detriment of IMPA and its members.*

IMPA's statement that they plan for the best expectation of future events based on information that is currently known is concerning. That is, IMPA does not seem to consider highly consequential events that are not currently known as a risk that should be examined. IMPA does not enumerate or detail the future events they expect.

## IMPA's Response to Director's Comments

“Regarding the IRP comment that IMPA plans for the best expectation of future events as being “concerning” (page 12), we believe the Director misunderstands the intent of the comment. In this statement, IMPA is explaining that we take a market-based view whenever possible and IMPA will take readily observable forward prices as the best proxy for the expectation for future prices/market conditions. IMPA believes that to take a view that is wildly different from market expectation is imprudent. This is not to say we ignore any “non-consensus” viewpoints or potential outcomes. While forward prices for IMPA's commodity exposures move daily, policy measures move much more slowly and IMPA closely monitors those events as part of its planning process. Policy risks, whether coming from a federal or state level or even ISO stakeholder process, are probably the biggest risk facing most utilities. There is no forward market for policy actions (other than perhaps predictit.org), but policy actions move at a much slower pace and utilities can shape policy actions through stakeholder processes. Finally, that statement was written in the context of being mindful about not overcommitting to a particular long-term plan given all the short-term uncertainty unfolding as the IRP was in progress (COVID-19, elections, etc). The ultimate intent was to convey that while the IRP set forth a short-term action plan, the level of uncertainty in the world might lead the plan to change depending on events unfolding concurrently with the publishing of our IRP. For example, the IRP was due on November 2nd and elections were held on November 3rd.” (*IMPA's Response to Director's Draft Report, page 10*)

## Director's Reply

*The Director appreciates IMPA's focus on short term actions given the extent of uncertainty over the longer-term. IMPA correctly notes that much of this uncertainty derives from the wide range of policy*

*choices that cannot be predicted nor controlled. It is just this circumstance that puts a premium on consideration of a wide range of possible futures developed based on different possible policy choices over the planning period. In this context, it is important to consider whether near term resource choices unreasonably hinder resource options further out in the planning horizon. It is the Director's opinion that this type of uncertainty analysis is best accomplished with scenario planning and supplemented with stochastic modeling.*

The IRP Report fails to include a well-developed discussion of how the potential retirement of generation resources was conducted. This consideration is highlighted where the optimized Green Scenario Portfolio lacked the inclusion of retirements. Was this caused by a lack of significant costs in the model associated with keeping the units available over a long period of time including high fixed operations and maintenance (O&M) and future capital expenditures? Is it accurate to say that Aurora will not retire generating units, even if they are frequently out of the money (i.e., not be dispatched due to market prices that are too low to warrant dispatch) if these types of costs are not considered? To be clear, the Director makes no finding about the reasonableness of the retirement analysis but, if the modeling did not include equipment replacement and other O&M, the costs of retaining these resources would be understated. IMPA's treatment of retaining generation or costs associated with retirement may alter the comparisons with other potential resources. These questions arise given the lack of discussion of how long-term generation unit O&M and ongoing capital costs are handled. The Director is interested in what was done, why, and how.

#### IMPA's Response to Director's Comments

"On retirements (page 10), the Director seems to be most concerned with the Green Case. To begin, all resources with publicly announced retirement dates were manually retired in Aurora (IRP 11-75). Second, any resource that has not announced a retirement date is nevertheless treated as retired when it reaches 60 years of age. Beyond these entered retirement dates, IMPA allowed Aurora to retire resources based on economics. Those units with slated retirement dates can be retired earlier by the model. The model determines retirements and additions by a rolling NPV of the resources.

Aurora converts overnight construction costs, local labor adders by region, and financing costs into an amortized fixed cost over the life of the asset. Aurora also carries default fixed costs for existing units based on their market research and IMPA staff updates these fixed costs for IMPA specific information and to account for additional capital investment in order to make the evaluation between existing assets and new assets more "apples to apples."

IMPA agrees the Green Case was somewhat curious. In 2026, the second year of an aggressive CO2 tax in the Green Case, Aurora selected to keep some coal-fired resources open while building a handful of combined cycle ("CC") units and building vast amounts of solar and wind. Solar and wind facilities do not receive the capacity credit of a coal or gas facility (or perhaps batteries in the future), so something must provide that capacity. At this point it becomes a question of whether it is more economical to leave an existing unit to act solely as a capacity resource or build an entirely new unit. These coal facilities that were left online had fairly low run times but were providing the needed capacity for the regions. An analysis of Aurora proformas shows that these facilities combined O&M, ongoing capital, fuel and CO2 expenses were less than the new build cost, O&M, ongoing capital, fuel and CO2 expenses of CC plants." (*IMPA's Response to Director's Draft Report, page 11*)

## Director's Reply

*The Director appreciates the additional information provided.*

Also, of concern to the Director is IMPA's conclusion not to include battery storage. A more objective analysis might be to consider storage in conjunction with renewable resources and other DERs (HES). IMPA contends that "Storage assets were strongly considered. However, after an internal review of comparative economics and business use cases undertaken in the Fall/Winter of 2019/2020, IMPA opted not to consider storage assets for this IRP." (*IMPA IRP page 11-68*) The Director understands the difficulty of modeling battery storage because of the broad range of potential applications and limited incidence of batteries in IMPA's service territory but even an elementary analysis might have provided useful insights. Certainly, future IRPs should give more considered analysis of battery storage. As with other DERs and HES, IMPA would be well-served by obtaining more detailed operational data on battery storage to assess the potential implications for IMPA and its communities.

## IMPA's Response to Director's Comments

"To expand on the analysis of storage assets on 11-68, Aurora models new resources strictly from their value to the RTO markets (i.e., energy and capacity value). Based on IMPA's internal analysis for a small battery of around 2 MW, the fixed annual energy revenue requirement far exceeds the revenue requirements for other energy market resources. In its internal analysis of battery storage, IMPA concluded that the economics of storage could potentially be beneficial in transmission applications or behind the meter applications, neither of which are explicitly handled in Aurora's market expansions.

IMPA fully anticipates expanding the modeling of battery storage systems in ongoing analysis and future IRPs." (*IMPA's Response to Director's Draft Report, page 12*)

## Director's Reply

*The Director appreciates IMPA's expectation that future IRPs will include expanded modeling of battery storage systems. Colleagues at the State Utility Forecasting Group have noted that the modeling of battery storage in Aurora has limitations. Hopefully these limitations will be lessened or eliminated in the near future. The Director understands that battery storage technology was regarded as nascent at the time IMPA prepared this IRP.*

Despite IMPA's recognition that EV penetration is growing and the purpose of IRPs is to plan for a twenty-year planning horizon, IMPA seems to dismiss the potential ramifications of EVs.

While there may be some pockets of load growth due to increased EV penetration in a carbon adverse world, IMPA believes those are likely to be drivers in urban areas. While it is too early to tell for certain, there also appeared to be some demographic shifts away from cities and into more rural areas during the COVID pandemic. Should these remain in place, that may mute any impacts from EV penetration. While EV penetration is undisputedly growing, it is notable that publicly accessible charging infrastructure is still relatively early in adoption in the United States. (*IMPA IRP page 12-06*)

Given that charging infrastructure will affect the distribution system's planning and operations and the additional EV energy and demand will affect the reliability of the IMPA system (including

potential shifts in demand) the absence of greater interest in EVs seems inappropriate and IMPA has made no statement that they anticipate developing data to prepare for an increase in EVs and charging infrastructure. It also seems inappropriate to assume that COVID-19 mitigates any effects of EV penetration.

It is important to reiterate that, especially since the IRP is a long-term load and resource analysis, it would be appropriate for IMPA to consider battery storage and DERs as selectable resources. Battery storage and DERs should be included in the scenarios to ascertain whether the portfolios could be improved (e.g., resulted in a lower revenue requirement or improved resource adequacy) or result in diminished benefits. Moreover, according to the MISO, system reliability and the economic value can be at risk throughout the year, which should be considered in IMPA's scenarios and portfolios.

The reliable and economic integration of renewables has been a source of considerable interest by MISO and utilities generally. Given the increasing importance of renewable resources, IMPA's statement regarding the installed costs of solar panels seems to be little more than an assertion. IMPA said: "...as for renewable technology, any increases in demand for panels and inverters are likely to be met with increases in technological advancement and efficiency. Ultimately, this, in IMPA's view, leads to a net zero change in cost per installed watt for solar." (*IMPA's IRP page 12-109*)

In the absence of empirical evidence, it may or may not be valid to assume demand for panels will keep capital cost of the panels to remain the same over time even with technological improvements. This assumption is too important to assume this outcome for future IRPs without empirical support. The analysis of possible implications of alternative cost assumptions could have provided insight into how sensitive resource selection is to changes in key parameters.

In summation, without analysis of the integration of all forms of DERs (including battery storage), EVs, and renewable resources, it seems likely that the potential effects of all forms of DERs and EVs are understated. As a result, the lack of information about DERs, EVs, and renewable resources prevents IMPA from fully assessing its current and future resource mix.

## **D. Future Enhancements to IMPA's IRP Processes**

### **Director's Comments - Future Enhancements to IMPA's IRP Processes**

IMPA did not advance any proposals for improving the interrelated elements of its future IRPs. This is inconsistent with the IRP rule which requires continual improvements. Considering the potential increases in DERs (including batteries) and EVs, it would be appropriate to obtain information about the ramifications of DERs and EVs.

The Director understands that IMPA is reliant on its member communities to undertake DSM programs. However, without higher quality and quantity of very discrete (sub-hourly) load data and detailed information about IMPA's and its member communities' ultimate customers, the credibility of load forecasts is diminished, and it limits the ability to develop more accurate rate design based on all avoided costs (generation, transmission, and distribution) of the resource.

Despite IMPA's use of state-of-the-art planning tools such as the Aurora model, the lack of high-quality data is a glaring deficiency that constrains the value of planning tools to develop improved

load forecasting, assessing planning risks, enhanced rate design, and calculate the dynamic value of DERs.

### IMPA's Response to Director's Comments

"IMPA appreciates the Director's comments on IMPA's lack of proposed improvements. To begin, with a modeling resource such as Aurora, IMPA strives to strike a balance between supplying data and narrative... In an effort to make this year's IRP more readable, IMPA attempted to be judicious in its presentation of supplemental information. Going forward, IMPA will err on the side of more information rather than less as well as improve the analysis and discussion of certain technologies.

Also, as a note for future reference, IMPA has begun the early phases of evaluating power supply modeling platforms to determine if we should stay with Aurora or move to something else. IMPA undertakes these evaluations as means to not only improve our internal analyses, but to improve the robustness of the IRP process." (*IMPA's Response to Director's Draft Report, page 13*)

### Director's Reply

*The Director appreciates the difficulty of preparing and presenting a well written and well documented IRP. In some respects, the lack of a public stakeholder advisory process may increase the burden on IMPA (and the other not-for-profits) when it comes to presenting their analysis in the IRP report.*

## **IV. SUMMARY**

The load forecast continues to be the foundation for the IRP. Based on recent history, the results of the forecast seem reasonable, especially in the short-term. The discussion of some of the possible implications of the pandemic were interesting. The longer-term forecast was less informative and concerning, largely due to there being no discussion of the development of bands around the energy and peak demand forecasts or alternative load scenarios. There was a lack of information and a failure to consider the potential forecast implications of all forms of DERs (including battery storage), EVs and the attendant charging requirements on IMPA's members' distribution systems, and potential loss (or gain) of customers (member communities or their customers). The Director understands that DERs – including batteries and EVs – are not currently significant, but IMPA needs to understand the potential ramifications for the IMPA system. It is just these types of considerations with a large degree of uncertainty that could have been addressed with alternative load scenarios.

The Director understands the organizational constraints that limit the quality and quantity of retail customer data available to IMPA. However, IMPA does not seem to acknowledge that changing economics and technology will make coordination between IMPA and its members more important. Just as MISO is looking at how it needs to change and enhance the exchange of information with its market participants, IMPA will eventually need to consider how to better coordinate various operational and planning activities with its members.

IMPA's narrative of DSM is not informative and not sufficiently detailed. Again, IMPA's ability to understand its customers' needs is constrained by a lack of detailed load research information. As a result, and notwithstanding IMPA's comments, the information on how the DSM programs were valued, calculated, and treated on a reasonably comparable basis to other resources is not clear.

IMPA's discussion of the future of the existing resources (e.g., the analysis to retain or retire some facilities) was too limited to be of value in an IRP. The scenario and portfolio analysis were limited to a relatively tight risk bandwidth which suggests that IMPA did not give due regard to low probability events that were significantly impactful if they occur. The failure to include a reasonable analysis of all forms of DERs and EVs seem likely to affect long-term resource decisions that were not included in this IRP.

Finally, IMPA did not offer any improvements, which is inconsistent with the IRP rule.

#### IMPA's Response to Director's Comments

"DERs and EVs: The director commented that the effects of DER and EVs were small at this time but could be large in the future. IMPA acknowledges that analysis of expanded customer generation was lacking. Customer generation is a customer choice and it is difficult for a utility to model customer decisions that may be based on much different factors than utility decisions. Going forward, IMPA will include more analysis and discussions of the effects of DER, EVs and their effect on IMPA's long term load forecast(s) and member distribution systems.

Organizational constraints: The director acknowledged the organizational relationship and difficulties in data sharing between IMPA and its members but encouraged a greater coordination of data between IMPA and its member systems. Data acquisition between IMPA and its members always has and continues to be a challenge. IMPA will work on ways to educate and work with member communities to increase the flow of information between IMPA and the members.

Existing resources: The director suggested that IMPA's discussion of existing resources and future decisions was too limited. Going forward, IMPA will include greater discussions of such decisions and include any internal reports regarding such decisions in the Appendix." *(IMPA's Response to Director's Draft Report, page 13)*

#### Director's Reply

*The Director appreciates the commitments to continued improvement.*

## **V. STAKEHOLDER COMMENTS**

The public input to IMPA's IRP is limited, as there is no public participation process comparable to that required for investor-owned utilities. Only one set of written comments was submitted, and it was provided by the Sierra Club.

As a preliminary matter, the Director will take this opportunity to remind all stakeholders of the limitations spelled out in IRP administrative rule on the appropriate content of the Director's report. According to 170 IAC 4-7-2.2(g), the Director's report can only address:

- (g) The draft report and the final report shall:
- (1) be limited to commenting on the IRP's compliance with the requirements of this rule;
  - (2) list the areas where the director believes the IRP fails to comply with the requirements of this rule; and
  - (3) not comment on:
    - (A) the desirability of the utility's preferred resource portfolio; or
    - (B) a proposed resource action in the IRP.

Given these guidelines, the Director will limit discussion of stakeholder comments that appear to target the resource portfolio developed by the IRP process or specific resource actions in the IRP. The Director will try to highlight stakeholder comments that address issues or questions about models, methodology, data, assumptions, and criteria used to evaluate the output of the IRP analyses.

---

### Sierra Club

Sierra Club made three recommendations to improve IMPA's resource planning.

First, IMPA has failed to study the economics of its most-expensive coal unit, Whitewater Valley, which is approximately double the cost of Gibson unit 5, a unit that is on track to retire within the next half decade. IMPA should produce an addendum to the IRP to properly evaluate the economics of maintaining Whitewater Valley versus retiring it. Second, IMPA should consider a clean energy portfolio that would provide the same services as its existing units for lower cost and less pollution. Third, IMPA should update its resource planning to consider energy storage as a resource option. *(Sierra Club Comments page 1)*

To estimate the long-run margin of Whitewater Valley, Sierra Club constructed a model to project future costs and revenues. All assumptions and projections are derived from publicly available information. *(Sierra Club Comments page 7)*

For the Clean Energy Portfolio analysis, Sierra Club used the Rocky Mountain Institute's Clean Energy Portfolio's algorithm from the 2019 report "The Growing Market for Clean Energy Portfolio's" to identify a suite of clean energy technologies (wind, solar, storage, energy efficiency, and demand response) that could replace the services of the coal plants IMPA receives energy and capacity from: Gibson 5, Prairie State, and Whitewater Valley.

A clean energy portfolio, or CEP, is a combination of renewable energy, storage, and demand-side management (DSM) projects that meet the needs of the grid and a utility's customers. We use the term DSM to collectively refer to energy efficiency projects (which lead to a reduction in load) and demand response projects (which lead to the shifting or temporary reduction of load). The use of CEPs differs from traditional resource planning, which typically focuses on a specific technology. Instead, a CEP looks at how a range of available clean energy resources could contribute in each hour of the year, and finds the combination that meets the unique needs of customers at the lowest feasible cost. In this study, the CEPs are constructed to match the energy, peak capacity, and ramping characteristics of the JH Campbell coal plant unit 3. Portfolios are optimized to satisfy these needs at the lowest cost possible. *(Sierra Club Comments page 8)*

Regarding storage, Sierra Club also recommended IMPA consider using costs from the National Renewable Energy Laboratory's 2020 ATB Study.

### **Director's Response**

The Director appreciates the comments submitted by Sierra Club and the focus on planning methodology and analysis improvements.

The Director agrees that IMPA could have done a better job documenting how the continued operation of specific generation facilities was evaluated, the data used, and the sensitivity of the analysis to variations in projected futures. The analysis might have been well developed, but the lack of discussion makes it impossible to know. Indiana utilities are increasingly including specific and detailed written discussions in their IRPs of how they evaluated the continued operation of generation units and the results. As the Director has stated many times, the purpose of the IRP is to help drive better analysis and, perhaps more importantly, to provide an opportunity to more fully document and explain what, how, and why something was done, and how the resulting information was used.

The Director understands Sierra Club has traditionally focused on EE. The IRP rule is more expansive, but the Director has no objection to Sierra Club's analysis. As part of a more expansive definition of DERs and HES (including battery storage), the Director urges IMPA to not only consider EE but also other forms of DERs and the potential effect on the resource selections. To facilitate cost-effective EE and other DERs, the Director has consistently encouraged IMPA (and all Indiana utilities) to calculate the relevant avoided costs that vary by time and location.

IMPA's analysis of DERs was lacking, not just regarding storage. The Director understands that DERs are currently a minor consideration and that IMPA's structural relationship with its members creates barriers to a sound analysis. However, the importance of DERs is likely to increase from its current very low rates, so the Director encourages IMPA and its members to use this time to better understand the potential implications should circumstances change more quickly than IMPA assumes to be the case. Also, IMPA is encouraged to use a range of projected cost data to evaluate the potential of DERs and the sensitivity of its analysis to variations in data and assumptions.